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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769	Rulemaking 14-08-013 (August 14, 2014)

COMMENTS OF THE CALIFORNIA SOLAR ENERGY INDUSTRIES ASSOCIATION ON THE ORDER INSTITUTING RULEMAKING

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The California Public Utilities Commission (Commission) issued an order instituting rulemaking (OIR) creating the above captioned proceeding on August 14, 2014 and solicited comments on the OIR by September 5, 2014. The California Solar Energy Industries Association (CALSEIA) respectfully submits these comments.

1. INTRODUCTION

CALSEIA appreciates the opportunity to comment on this forward-thinking OIR. Given the growth and emerging capabilities of Distributed Energy Resources (DERs), it is critical that these resources are effectively incorporated into the utilities' distribution planning efforts. This will enable the state to maximize assets, avoid unnecessary spending, and facilitate the decarbonization of our electric grid. CALSEIA believes the OIR poses the right questions and the paper included as Attachment B provides an effective framework to help guide this effort. As required by AB 327, now is the right time to update utility forecasting methodology and rethink distribution resources plans (DRPs) to incorporate advanced grid functionality.

2. RESPONSES TO QUESTIONS

1) What specific criteria should the Commission consider to guide the IOUs' development of DRPs, including what characteristics, requirements and specifications are necessary to enable a distribution grid that is at once reliable, safe, resilient, cost-efficient, open to distributed energy resources,

and enables the achievement of California's energy and climate goals?

California investor-owned utilities spend significant resources each year on the distribution system. Grid planning should evolve to reflect the expanded role that distributed energy solutions increasingly play in the provision of energy services, consistent with the requirements of AB 327.

In the near term, the state has set targets of 12 GW of distributed generation and 1.3 GW of storage, and the current pace of installations suggests that those targets are feasible. In the longer term, the state's greenhouse gas (GHG) reduction targets, which call for reducing GHG emissions to 80% below 1990 levels by 2050, require a fundamental rethinking of how we generate and use energy and will serve as an important catalyst for even higher levels of distributed generation. A study by Lawrence Berkeley National Lab modeled eleven scenarios for achieving the state's GHG emission reduction target. The average statewide total installed solar capacity in 2050 in these scenarios is approximately 100 GW.[1] This means we will likely have to install an average of 2.5 GW of solar every year from now through 2050 to meet our climate targets. To be consistent with the statutory mandate, the DRPs should be developed to promote a highly communicative, nodal system that can accommodate 2.5 MW of new distributed generation every year, in addition to energy storage and automated demand response.

This will involve the ability to manage virtual power plants, the aggregation of many DER systems into one, with proper communication protocols at the node/distribution level to manage and dispatch resources when and where needed. The grid must be "plug and play," be capable of two-way electricity flows, and ensure reliability and power quality.

2) What specific elements must a DRP include to demonstrate compliance with the statutory requirements for the plan adopted in AB 327?

AB 327 directs the utilities to submit DRPs that, "Evaluate locational benefits and

[1] Lawrence Berkeley National Laboratory, "California's Carbon Challenge: Scenarios for Achieving 80% Emissions Reduction in 2050," Figure 10-12,

costs of distributed resources located on the distribution system."[2] One element that is necessary to do this is a clear specification of all of the maintenance and upgrades to the distribution system with and without increased DER. Utilities should include at least three scenarios: a base case of expected DER, low growth in DER, and high growth in DER.

Locational benefits are not a matter of where DER is needed and where it is not. Widespread adoption of DER is needed to meet our GHG targets and transform the grid to a more resilient, nodal system. Locational benefits are a matter of learning how to maximize distributed assets from a grid planning perspective. DRPs must include plans for realizing benefits of DER and proposals for recovering the costs of doing so.

3) What specific criteria should be considered in the development of a calculation methodology for optimal locations of DERs?

The most important locational characteristic is proximity to load. Any generation or demand response asset that effectively removes load from the distribution system will reduce the strain on distribution equipment and the need for system expansion.

Coincidence between peak output of distributed generation and peak demand is another important criterion. Feeders with demand that peaks during episodes of high temperatures will benefit from the addition of distributed solar.

DRPs need to analyze the impacts of DER growth not only in terms of the marginal benefits of each additional generating unit but in terms of benefits from the amount of generation that may be added over decades. A base case scenario should be developed for the entire distribution system and the costs of grid modernization calculated for each geographic area of the distribution system. Utilities should consider long-term distribution system investment needs and how much those investments can be deferred by potential increases in DER as a whole throughout the system over time.

4) What specific values should be considered in the development of a locational value of DER calculus? What is optimal means of compensating DERs for this value?

Two categories of value from DER are: a) the ability to defer maintenance and upgrades to distribution system components due to decreased net load, and b) the

[2] Public Utilities Code section 769 (b)(1).

provision of ancillary services to maintain power quality.

Utility infrastructure costs are amortized over periods of time stretching as long as 50 years, and most distributed generation will be producing electricity for at least 30 years. To determine the benefits of DER, we must measure the extent to which any investments over the following 30-50 years will be deferred by increases in local generation.

For circuits that already have high penetration of DER, near-term upgrade deferment will be a significant value and will translate into a valuable benefit to be shared with customers. For circuits that have recently been upgraded and have large amounts of available capacity, this value will be smaller but is still calculable.

As mentioned below, a framework for ancillary services is being developed in Rulemaking (R.) 11-09-011. This proceeding should coordinate with that proceeding to assess the value of those services.

Regarding compensation, AB 327 directs the utilities to, "Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives."[3] Two of those objectives are transitioning the grid toward a nodal system and facilitating the deployment of grid reliability services as the penetration of DER increases.

One mechanism to consider for compensating DERs for value to the grid is a volumetric credit for distributed generation systems in areas that are targeted for increased DER. This could be an amount per kWh exported to the grid, and could be a temporary credit that lasts a period of time such as five years.

Because these targeted areas will change over time and because it is not clear how expansive they will be, it is not reasonable to make the compensation mechanism such a strong price signal that it does not make sense for the average customer located outside of a preferred area to install DER without the locational adder. Distributed energy solutions providers have to be able to assume some level of continuity in local markets if they are going to invest in employees, infrastructure, and marketing in order to make services available to customers. It is not realistic to expect solutions providers to chase price signals around the state. The standard tariff for distributed generation customers, being

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[3] Public Utilities Code section 769 (b)(2).

developed in R.14-07-002, must be a viable option on its own. A locational adder can then be effective at making DER cost-effective for a wider range of customers in targeted locations.

5) What specific considerations and methods should be considered to support the integration of DERs into IOU distribution planning and operations?

Behind-the-meter generation and grid support assets must be included in forecasting for resource adequacy and long-term planning. To do this, the Commission must develop a methodology to estimate expected production based on installation specifications.

Currently, utilities use production estimates from “utility-scale” renewable energy facilities but ignore customer installations. Evidently they do not have enough trust that myriad dispersed customer-generators will actually have their generating facilities on-line as expected. This mistrust is unwarranted. Solar systems are highly reliable. When the sun is shining, customer-sited solar systems can be counted on to produce electricity.

When the sun is not shining, system demand is reduced in most cases. For those circuits that are highly temperature dependent, the full projected production of distributed solar can be used for distribution system planning. For those circuits where load and temperature do not correlate consistently, solar production can only be counted on to the extent that the circuits contain demand response mechanisms to suppress demand at times of low solar production due to cloudy weather. Utilities should do an analysis to measure the extent to which the demand on each circuit is temperature dependent and flexible. This can be a sliding scale for each circuit that is recalibrated annually, serving as a de-rate factor on projected solar production for purposes of distribution system planning.

Upstream distribution capacity is not as dependent on local load characteristics since load is effectively averaged over a large number of customers. Calculating the need for and timing of upgrades to upstream distribution capacity can therefore fully integrate projected production from distributed solar.

On the topic of grid support, the compatibility of advanced inverter functionality and interoperability of distributed inverters should be considered. This includes the infrastructure to communicate with distributed inverters in real time. In this, the proceeding can coordinate with the smart inverter standards development in R.11-09-011.

Much of the communications and financial transactions can be managed by third party providers. Utilities can assume that a robust industry of DER service providers will emerge to manage retail transactions.

6) What specific distribution planning and operations methods should be considered to support the provision of distribution reliability services by DERs?

This is a question that is currently being addressed in part by the Smart Inverter Working Group in Rulemaking 11-09-011. This proceeding can coordinate with that proceeding rather than duplicating the work.

The Working Group is currently developing the technical specifications for communications protocols. This includes the question of how the utilities will interact with distributed inverters that have advanced grid functionality. When that is concluded the Working Group will consider rules and standards for utilities to send commands and price signals to inverters to perform distribution reliability services. Materials produced in that process should be incorporated by reference in this proceeding.

7) What types of benefits should be considered when quantifying the value of DER integration in distribution system planning and operations?

Distribution capacity, grid support services, and security benefits should all be considered. As detailed in a Rocky Mountain Institute report,[4] grid support services include:

- Reactive supply and voltage control
- Regulation and frequency response
- Energy and generator imbalance
- Synchronized and supplemental operating reserves
- Scheduling, forecasting, and system control and dispatch

Since a nodal grid will be more reliable and resilient if properly constructed, these benefits must also be quantified.

8) What criteria and inputs should be considered in the

[4] Rocky Mountain Institute, "A Review of Solar PV Benefit and Cost Studies," September 2013.

development of scenarios and/or guidelines to test the specific DER integration strategies proposed in the DRPs?

Scenarios should be constructed in order to develop the strategies in the DRPs, not to test strategies that are developed without scenarios. Creating a base case scenario of DER expansion should be the first order of business. From there, the utilities can determine the grid architecture that will be needed to manage those resources and how to encourage higher levels of DER in the areas where it is most beneficial. As mentioned above, low and high DER growth scenarios should also be considered.

9) What types of data and level of data access should be considered as part of the DRP?

A detailed list of distribution system expenditures is essential for determining the cost of transforming the grid into a nodal system. Traditionally, utility expenditures on distribution have been a "black box." General rate cases are decided by settlement, which avoids disclosure of detailed budget line items. To determine where to avoid stranded costs and unnecessary expenditures and to steer distribution dollars toward grid modernization, historical and projected expenditures must be provided.

It will also be essential to know the current penetration of DER on each circuit throughout the state, along with energy storage capacity and automated demand response. In AB 327, the Legislature has directed the Commission to evaluate utility plans that include, "avoided or increased investments in distribution infrastructure."[5] There will be no way to do that without detailed data.

10) Should the DRPs include specific measures or projects that serve to demonstrate how specific types of DER can be integrated into distribution planning and operation? If so, what are some examples that IOUs should consider?

CALSEIA has no response at this time.

11) What considerations should the Commission take into account when defining how the DRPs should be monitored over time?

DRPs will need to be updated on a regular basis. Utilities should ensure that the Commission has the data necessary to determine how well actual spending matched

[5] Public Utilities Code section 769 (b)(1).

planned expenditures and the reasons for any divergence between the two.

12) What principles should the Commission consider in setting criteria to govern the review and approval of the DRPs?

DRPs should be subject to review and comment from parties, and Commission decisions to approve or modify DRPs should also be open to comment.

Some good principles for review are contained in the "More than Smart" paper in Appendix B of the OIR:[6]

- Plans should be scenario-driven rather than reactive to incremental DER expansion.
- Plans should give "greater access to grid operational and market planning data."
- Development of plans should include an "Integrated multi-stakeholder distribution planning process."
- Plans should achieve optimal system performance, optimize assets, be resilient, accommodate technological innovation, accommodate new business models, be scalable, be open and interoperable, mitigate security threats, and maintain public safety.

13) Should the DRPs include discussion of how ownership of the distribution may evolve as DERs start to provide distribution reliability services? If so, briefly discuss those areas where utility, customer and third party ownership are reasonable?

CALSEIA has no response at this time.

14) What specific concerns around safety should be addressed in the DRPs?

CALSEIA has no response at this time.

15) What, if any, further actions, should the Commission consider to comply with Section 769 and to establish policy and performance guidelines that enable electric utilities to develop and implement DRPs? Attachment 1 to this order is a complete copy of AB 327 as enacted.

CALSEIA has no response at this time.

3. CONCLUSION

[6] OIR, Appendix B at 10-11.

CALSEIA appreciates the opportunity to provide these comments. We thank the Commission for issuing a forward-thinking OIR and urge the Commission to incorporate the recommendations above.

DATED at Santa Rosa, California, this 5th day of September, 2014

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